Alberta
ENERGY

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09-08

GAS ROYALTY CALCULATION INFORMATION BULLETIN August 2009

A. PRICING RATES AND TRANSPORTATION INFORMATION
Pricing, Royalty Rates and Transportation Information – June 2009 2

B. NOTICES
Incorporating Greenhouse Gas (GHG) Emission Compliance Costs into the Natural Gas Royalty Regime 2

C. MONTHLY INFORMATION
June 2009 Royalty Due September 30... 4
July 2009 VA4 Due September 15 4
Registry Deadline Submissions... 4
Interest Rate August 2009... 4
May Provisional Assessment Charge... 5
May Penalty Charges 5
Gas Royalty Calculation Support... 5

D. INFRASTRUCTURE DATA CHANGES
Client ID Listing... 5
Client Status Changes... 6
Nova Tolls – Multiple Gas Reference Prices... 6

E. REMINDERS
Drilling Royalty Credit Working Interest Owners for Oil Royalties 6
Well Event Measured Depth Determination Letter 7
2009 Allowable Cost Allowances (Capital Cost, Custom Processing Fee and Operating Cost Allowances) 7
Operating Costs Subject to Recapture 8

F. POINTS OF CONTACT
Petroleum Registry of Alberta 8
Alberta Energy internet... 9
Gas Royalty Client Services... 9
Reference Prices and Valuation Allowances Calculation Information 10

PLEASE ENSURE YOUR PRODUCTION ACCOUNTANTS RECEIVE A COPY OF THIS DOCUMENT.

A. PRICING RATES AND TRANSPORTATION INFORMATION

For Pricing, Royalty Rates and Transportation Information for June 2009, refer to Attachments 1, 1A, 2, 2A and 3. These attachments are also available in Excel Format.

B. NOTICES

INCORPORATING GREENHOUSE GAS (GHG) EMISSION COMPLIANCE COSTS INTO THE NATURAL GAS ROYALTY REGIME

As announced in the Information Letter 2009-25, Alberta Environment introduced the Specified Gas Emitters Regulation (SGER) in July 2007, to meet compliance requirements for the reduction of greenhouse gas emissions. The SGER provides industry with the following options to meet compliance requirements:

- Implementing capital projects or improving facility operations
- Purchasing emission offsets
- Purchasing or selling performance debits/credits
- Purchasing Climate Change & Emissions Management Fund (the Fund) credits.

Effective July 1, 2007, the department will recognize capital costs, operating costs, and custom processing fees resulting from compliance with the SGER, provided the costs are incurred and paid in Alberta, as allowable costs for Crown royalty purposes. The Crown will recognize the costs incurred from purchasing Alberta based emission offsets, performance debits/credits and the Fund credits as allowable costs. The Crown will also share proportionately in any revenue earned from the sale of performance credits. Any penalties levied for non-compliance under Section 28 of Alberta Environment's SGER are not deemed as allowable costs.

As the breakdown in custom processing and capital costs is not always transparent, or it may be difficult for royalty clients to identify costs associated with GHG emission compliance costs, these costs may not be distinguished in the reporting of capital cost and custom processing fee allowances. Facility operators/designated royalty clients may have already claimed these costs, but if not, cost forms should be amended to include costs where necessary.

A breakdown in the reporting of operating costs is required. The operators must identify the operating costs associated with GHG emission compliance costs for Crown royalty purposes.

The royalty treatment of GHG emission compliance costs will be similar to other allowable costs:

- Deducted only by way of reductions from royalty compensation owing to the Crown for natural gas and gas products royalty
- May not exceed the total royalty compensation otherwise owed to the Crown for natural gas and gas products royalty for that year
- Allowable costs, which are not recovered in that year, may not be carried forward to a subsequent year
- Subject to audit

Reporting of Operating Costs for Production Years 2007 and 2008
(Reporting for periods covered by Natural Gas Royalty Regulation, 2002)

The current Allowable Operating Cost form for Production Year 2004 and Onwards (AC4-V2) does not allow a client to report GHG emission compliance costs separately from other allowable operating costs. In an effort to minimize system and form enhancements, the operating costs associated with purchasing emission offsets, performance debits/credits, or the Fund credits, are not to be reported on the AC4-V2 for production years 2007 and 2008.

In order to claim these operating costs, the operator of an ERCB facility required under the SGER to reduce GHG emissions, or the operator of an ERCB facility that has sold a performance credit to a facility to assist in compliance obligations, must submit a letter to the department, with supporting documentation. GHG emission compliance costs are to be claimed at an ERCB facility level. If applicable, facility operators must include the percentage of operating costs that is to be allocated to each working interest owner or designated royalty client.

Requests should be forwarded to the following address, before a production year becomes statute barred.

Attention: Wayne Taljit, Manager, Client Services
Gas Royalty Calculation
8th Floor NPP
9945-108 Street
Edmonton, AB T5K 2G6

Once the department has completed its review, an amendment will be processed. It will be reflected as a Financial and Volumetric adjustment on the facility operator's invoice. It is the operator's responsibility to allocate the credit amongst the working interest owners. An allowable cost restriction will apply if the Crown share of allowable cost deduction exceeds the total royalty compensation owed to the Crown by the royalty client. This restriction will be manually applied at the Working Interest Owner level. The department will monitor this adjustment until the production year becomes statute barred.

Reporting of Operating Costs effective Production Year 2009
(Reporting for periods covered by Natural Gas Royalty Regulation, 2009)

A separate line item will be included on the Capital and Operating Cost Allowance form (AC2-V4) to capture GHG emission compliance costs. These costs should be reported separately from the other allowable operating costs as they are not subject to overhead and working capital allowance adjustments. The new AC2-V4 form will be available in March 2010.

C. MONTHLY INFORMATION

June 2009 Royalty Due September 30

- **Royalty clients are to remit the total amount payable shown on the September 2009 Statement of Account by September 30, 2009.** If the amount payable includes accrued current period interest, the interest has only been accrued to the statement issue date. Clients must also include the additional interest that has accrued from the statement issue date to the date of payment, using the per diem amount provided.

- **The September 2009 Statement of Account shows your amount payable as of the Statement issue date. It includes any outstanding balances from your previous statement, your June 2009 invoice amount and any applicable current period interest charges. It also identifies refunds resulting from overpayments.**

- Current period interest will not be charged on current invoice charges for the production month of June 2009 if it is paid in full by September 30, 2009.

- Current period interest will accrue on any overdue charges commencing the first day after the due-date until it is paid in full.

  Note: If the due date falls on a non-business day, the next business day will apply as the due date.

- Cheques are payable to the Minister of Finance, Province of Alberta.

July 2009 VA4 Due September 15

The VA4 forms for the production month of July 2009 are due in the department offices by September 15, 2009.

Note: If the due date falls on a non-business day, the next business day will apply as the due date for VA4 forms.

Registry Deadline Submissions

The Registry deadline submissions for SAF, OAF, and Volumetrics are posted in the Petroleum Registry of Alberta website "Reporting Calendars" under Bulletin Board.

Changes to this calendar will be posted on the Registry website home page in "Broadcast Messages."

Interest Rate August 2009

Alberta Energy's interest rate for August 2009 is 3.25%.

May Provisional Assessment Charge

The summary of Provisional Assessment Charges for all production periods in the May 2009 billing period was:

First Time Provisional Assessment	Reversals of Provisional Assessments	Net Provisional Assessment
$3,737,703.95	($1,894,153.25)	$1,843,550.70

May Penalty Charges

The penalty table below shows at the form level, the total penalty charges and reversals, for the May 2009 billing period:

FORM	Penalty Charges	Penalty Reversals	Net Penalty Charges for 2009/05
AC2	$28,600	$0	$28,600
AC4	$0	$0	$0
AC5	$2,900	$0	$2,900
VA2	$0	$0	$0
VA3	$0	$0	$0
VA4	$1,000	$0	$1,000
Total	$32,500	$0	$32,500

Gas Royalty Calculation Support

Upon request, Gas Royalty Calculation staff will be available to meet with clients who need assistance with royalty reporting. Royalty clients requiring assistance are encouraged to contact your respective Gas Royalty Client Services portfolio representative, as identified in Section F of this bulletin, to arrange a meeting.

D. INFRASTRUCTURE DATA CHANGES

Client ID Listing

The BA Identifiers Report is a directory of Business Associate (BA) names, codes, status (e.g. struck, active, amalgamated, etc.), status effective dates, and effective August 2004, includes Working Interest Owner (WIO) role start/end dates.

This report is also published daily on the Petroleum Registry website at:

http://www.petroleumregistry.gov.ab.ca

The department reminds Business Associates to review their WIO role to ensure that the start and end dates are reflected correctly. If the BA does not have an active WIO role, the operators cannot allocate volumes to the BA for the relevant production periods through the SAF/OAF allocations.

- If a BA has a WIO role, then that BA can receive SAF/OAF allocations from the WIO role start date forward.
- If a BA has a WIO role with an end date, then they can only receive SAF/OAF allocations from the WIO role start date until the end date. Any SAF/OAF allocations after the end date will be rejected.
- If a BA does not have a WIO role start date, then that BA cannot receive SAF/OAF allocations.

Please contact Client Registry at 780-422-1395 if you have any questions regarding the information supplied on this listing.

Client Status Changes

Clients must ensure that all royalty documents are completed using only valid client names and IDs. It is critical that royalty clients use current legal client names and their appropriate IDs on all documents to ensure accurate royalty calculation and to prevent provisional assessment and penalties. Rejects will occur when invalid IDs are used.

If you require information regarding client names or IDs, please contact Client Registry at 780-422-1395.

Nova Tolls - Multiple Gas Reference Prices

Royalty information related to the implementation of the Factor Model negotiated with industry for determining Multiple Gas Valuation Prices is provided on the Natural Gas website's Royalty Related Information page under Facility Royalty Trigger Factors and Meter Station Ties.

E. REMINDERS

Drilling Royalty Credit Working Interest Owners for Oil Royalties

On March 3, 2009, the Government of Alberta announced a Drilling Royalty Credit for new conventional oil and natural gas wells. This credit will be paid to eligible companies on the basis of their company-wide Crown production of natural gas, oil and non-project oil sands. To ensure that the interests of all the Working Interest Owners (WIO) are taken into account, the department will be establishing credits for individual WIO. Each facility operator will be required to furnish to the department the names and Business Associate (BA) ID of WIO and the production attributable to each WIO for Oil Royalties.

To initiate the collection of the required information, the department has issued a 'Drilling Royalty Credit – Working Interest Ownership Determination' report to the 2008 facility operators. The report is available on the Petroleum Registry of Alberta. The operator must submit to the department the total Crown production for each WIO, aggregated for all facilities. This information must be submitted by letter to the department, no later than September 15, 2009.

For Gas Royalty clients, the WIO is already reported through the Owner Allocation Factor (OAF).

For further information, please contact Laurie Schneider at 780-422-9039.

Well Event Measured Depth Determination Letter

The department has issued a "Well Event Measured Depth Determination Letter" under the Report Package DOE – Gas to facility operators via the PRA on July 2 and 8, 2009. This letter shows the confirmed Measured Depth (MD) of each active well event that will be used to calculate the Depth Factor (DF) of the quantity component rate under the new royalty formula. A well event that is not listed on the letter and does not have a confirmed MD will receive a DF of 1. When the changes to the MD are confirmed by the department, a letter is issued to a facility operator who reports changes through the PRA to well event attributes affecting MD. All changes to the MD are applied on a go forward basis only, if a retroactive change is required, a written request must be submitted to the department. Facility operators are advised to submit well event attribute changes by the last day of the calendar month in order for timely determination of MD.

2009 Allowable Cost Allowances (Capital Cost, Custom Processing Fee and Operating Cost Allowances)

Effective January 2009, the Facility Effective Royalty Rate (FERR) replaced the Corporate Effective Royalty Rate (CERR) to determine the Crown share of cost allowances (capital, custom processing fee and operating cost allowances) at a client/facility level. Initially, the total estimated cost allowances were based on data published in the Allowable Cost Estimate (ACEST) report, issued in March 2009. Whenever there is a recalculation of the go-forward cost estimates generated by the system, the department will re-issue an updated ACEST report.

Capital Cost and Custom Processing Fee Allowances

For the April 2009 to March 2010 billing period invoices, the capital cost and custom processing fee estimates will be recalculated using the most recent 2008 AC2, AC3, and AC5 documents. The information identified in the 2008 AC documents was used to calculate the actual 2008 capital cost and custom processing fee allowances for each client/facility. These calculations become the royalty client's 2009 go-forward allowable cost estimates. The Crown share of allowable costs is determined by multiplying each client/facility's cost by its FERR, minus the total deductions received in the January, February, and March 2009 billing period invoices, divided by the months remaining in the year (nine (9) months as of the April billing period).

Operating Cost Allowance

For the May 2009 to March 2010 billing period invoices, the operating cost estimates will be recalculated using the most recent 2008 AC4 actual costs filed for the designated facilities and non-designated processing type facilities, and distributed by using the 2008 AC2 distribution percentages. In the absence of AC2 distribution percentages, the costs will default to the facility cost centre operator. Operating cost estimates for all other non-designated facility types (gathering and compression for sweet, sour and dry plants), will be recalculated using the most recent January 2008 to December 2008 production period total client/facility volumes, multiplied by the actual 2008 gathering and compression Unit Operating Cost Rates (UOCR). The recalculation occurs in the May 2009 billing period invoice. The Annual Operating Cost Adjustment (AOP) to adjust the UOCR is processed once a year in the February billing period invoice, issued in April. The actual 2008 UOCR and the 2008 AOP adjustment was calculated in the 2009 February invoice issued in April 2009.

Facility Effective Royalty Rate

For the May 2009 to March 2010 billing period invoices, the January 2009 to April 2009 production periods' Crown royalty data was used to recalculate the FERR by client/facility.

Manual Cost Estimate Changes

If a royalty client requires a change to the 2009 go-forward allowable cost estimates and/or the FERR, a written request with supporting documentation must be submitted to the Gas Royalty Client Services (see Chapter 6, Section 1 of the Guidelines). These estimates must be calculated and submitted at a client/facility level.

Operating Costs Subject to Recapture

The Operating Costs Subject to Recapture report for the 2008 production year was issued in the April 2009 invoice in the June 2009 calendar month. Operating costs are recaptured from a royalty client who has volumes at a facility where they have no capital ownership (as identified on the AC1, AC2 or AC3 submission) and no reported custom processing fees. A royalty client who is not an owner at a facility is not entitled to the operating costs they received on a monthly basis. The operating costs subject to recapture will be charged in the August 2009 billing period invoice issued in October 2009.

F. POINTS OF CONTACT

Petroleum Registry of Alberta

The Petroleum Registry of Alberta Service Desk is the focal point for communications with the Registry regarding preparations for, access to, or utilization of the Registry. To contact the

Petroleum Registry of Alberta Service Desk call: 1-800-992-1144.

Alberta Energy Internet

Prices, Royalty Rates and Transportation Information are available on the Alberta Energy Internet address: www.energy.alberta.ca, from "Our Business", navigate to "Natural Gas", "About Natural Gas", "Prices", "Alberta Natural Gas Reference Price (ARP)".

In addition, both the Gas Royalty Information Bulletins and Information Letters are also available under "Our Business", navigate to "Natural Gas", "Legislation, Guidelines & Policies".

Gas Royalty Client Services

Gas Royalty Client Services is structured as a Business Associate client portfolio system, which assigns a given Business Associate to one of four Client Services teams. Listed below is the portfolio breakdown along with Client Services Team Leads and phone numbers. The portfolios are divided by company name and not by BA ID.

Example: If your company name is the "Gas Company" you would call C – G team at 780-644-1202.

Business Associate	Phone Number and Email Address	Team Lead
Numbered companies, A, B & L	780-644-1201 GRCST1@gov.ab.ca	Todd Atwood
C – G	780-644-1202 GRCST2@gov.ab.ca	Lily Hiew
H – P (excluding L)	780-644-1203 GRCST3@gov.ab.ca	Chris Nixon
Q – Z	780-644-1204 GRCST4@gov.ab.ca	Jyoti Bhambhani

Gas Royalty Reception: 780-422-8727
Fax: 780-427-3334 or 780-422-8732
Alberta Toll Free: 780-310-0000

Hours of operation are 8:15 a.m. to 4:30 p.m. Voice messages left after 4:30 p.m. will be answered the next business day.

In situations where a company has just amalgamated or purchased another company, the general rule is to call the team that is responsible for the "Supra" business associate, or Royalty payer. Below are some guidelines for clients who are unsure which Client Services Team to call regarding their questions.

1. **Amalgamation/consolidation** - Call the team responsible for the "Supra" business associate (Royalty Payer).
   i.e. ABC Oil and Gas amalgamates with Zed Exploration and Zed is the amalgamator (royalty payer). When calling Client Services regarding business for ABC Oil and Gas, you would call Team 4 (Q-Z) (780-644-1204) because Zed Exploration is now the Supra business associate and royalty payer. This rule would apply even if you were calling regarding business that is prior to the acquisition or amalgamation.

2. **Asset Purchase** - Call the team responsible for your company.
   i.e. 123 Gas purchases the assets of TSP Exploration, but not the company. When calling Client Services regarding business for 123 Gas, you would call Team 1 (# Co., A, B, & L) (780-644-1201) because you have only purchased assets.

3. **Consultants/service providers** - If you have a contract to provide production accounting services to a company, call the team responsible for your client's company.
   i.e. Paul Snow Consulting Services enters into a contract with Duckback Oil and Gas and Olive Oil and Gas. Paul Snow would contact Team 2 (C-G) (780-644-1202) to discuss Duckback Oil business and Team 3 (H-P excluding L) (780-644-1203) to discuss Olive Oil and Gas business. At the time the contract is signed, Paul Snow would have had each company notify the appropriate team that he was authorized to access information for their company.

Reference Prices and Valuation Allowances Calculation Information

Gas Royalty Valuation and Markets
300, 801 – 6 Avenue SW
Calgary, Alberta T2P 3W2
Telephone: 403-297-5514
Fax: 403-297-5400

Deen Khan
Director, Gas Royalty Calculation
Royalty Operations – Edmonton

Attachments

2009 GAS AND ISC PRICES

MONTH	Gas Reference Price ($/GJ)	Methane ISC Reference Price ($/GJ)	Methane ISC Par Price ($/GJ)	Ethane ISC Reference Price ($/GJ)	Propane ISC Reference Price ($/GJ)	Butane ISC Reference Price ($/GJ)	Pentanes plus ISC Reference Price ($/GJ)
JAN	5.77	5.74	5.74	6.15	6.27	6.29	6.31
FEB	4.66	4.61	4.61	5.12	5.30	5.33	5.35
MAR	4.01	3.97	3.97	4.53	4.71	4.72	4.75
APR	3.41	3.35	3.35	3.88	4.09	4.12	4.14
MAY	3.13	3.10	3.10	3.42	3.53	3.56	3.58
JUN	2.97	2.94	2.94	3.30	3.42	3.44	3.46
JUL							
AUG							
SEPT							
OCT							
NOV							
DEC							

2008 Weighted Average Gas Reference Price ($/GJ)
7.412

2008 Weighted Average OMAC ($/GJ)
0.019

DETAIL OF THE JUNE 2009 GAS AND ISC REFERENCE PRICES						
	Gas	Methane	C2-IC	C3-IC	C4-IC	C5-IC
Weighted Average Price of Alberta	3.288	3.273	3.503	3.573	3.567	3.566
Deductions: Intra – Alberta Transportation	0.265	0.282	0.161	0.113	0.087	0.066
Marketing Allowance	0.010	0.010	0.010	0.010	0.010	0.010
Price Before Pipeline Factor	3.013	2.981	3.332	3.450	3.470	3.490
Pipeline Fuel/Loss Factor	0.992	0.992	0.992	0.992	0.992	0.992
Price before Special Adjustment	2.989	2.957	3.306	3.423	3.443	3.463
Special Adjustment	0.000	0.000	0.000	0.000	0.000	0.000
Price before 2% amendment limitation or rounding	2.989	2.957	3.306	3.423	3.443	3.463
Amendments: Carry forward (from previous RP month)	-0.004	-0.002	0.003	-0.001	0.000	0.002
Prior Period Amendment Adjustment (current RP month)	-0.010	-0.011	-0.006	-0.004	-0.003	-0.003
Calculated RP after Amendments	2.975	2.944	3.303	3.418	3.440	3.462
June 2009 Reference Price	**2.97**	**2.94**	**3.30**	**3.42**	**3.44**	**3.46**
Difference = value carried forward to next RP month	0.005	0.004	0.003	-0.002	0.000	0.002
Adjusted IATD (before Prior Period Amendments)	n/a	0.280	0.160	0.112	0.087	0.066
Prior period Amendments (IATD and Pipeline Fuel Loss)	n/a	0.000	0.000	0.000	0.000	0.000
Adjusted IATD (after Prior Period Amendments)	n/a	0.280	0.160	0.112	0.087	0.066

2009

NATURAL GAS LIQUIDS PRICES

MONTH	Ethane Reference Price ($/GJ)	Ethane Par Price ($/GJ)	Propane Reference Price ($/m3)	Propane Floor Price ($/m3)	Butane Reference Price ($/m3)	Butane Floor Price ($/m3)	Pentanes plus Reference Price ($/m3)	Pentanes plus Par Price ($/m3)	Sulphur Default Price ($ per tonne)
JAN	6.15	6.15	230.29	209.33	310.61	206.67	348.86	325.57	21.41
FEB	5.12	5.12	258.66	188.18	277.46	185.58	332.24	304.31	9.42
MAR	4.53	4.53	191.60	170.24	311.71	180.47	405.64	380.07	35.33
APR	3.88	3.88	171.72	169.45	298.88	176.85	399.85	370.33	28.70
MAY	3.42	3.42	168.58	167.74	297.93	187.74	423.40	391.47	25.58
JUN	3.30	3.30	201.00	191.86	357.43	242.85	470.29	450.47	12.82
JUL									
AUG									
SEPT									
OCT									
NOV									
DEC									

ANNUAL SULPHUR DEFAULT PRICE

2004	2005	2006	2007	2008
31.88	33.98	18.82	32.82	$296.50

2009

NGL TRANSPORTATION ALLOWANCE AND DEDUCTIONS

MONTH	PENTANES PLUS (a)				PROPANE AND BUTANE (b)				PENTANES PLUS, PROPANE & BUTANE (c)				FRAC. ALLOW. (per m3)
	REGION				REGION				REGION				
	1	2	3	4	1	2	3	4	1	2	3	4	
JAN	27.97	10.55	36.88	18.00	39.25	25.79	33.99	-3.31	40.23	45.50	43.56	29.53	17.25
FEB	25.80	30.88	42.93	25.11	27.25	12.51	21.86	-11.81	46.71	47.25	67.48	33.91	17.25
MAR	26.82	21.32	38.98	22.16	37.54	27.84	31.17	-40.67	58.25	52.01	64.22	45.99	17.25
APR	28.19	26.90	45.36	29.98	42.87	25.56	35.55	8.19	55.88	50.16	60.38	42.39	17.25
MAY	29.40	28.03	63.30	29.70	33.17	20.09	88.53	46.06	46.67	43.29	56.38	34.81	17.25
JUN	14.94	23.55	36.40	25.25	40.56	35.36	38.57	60.65	61.31	51.83	60.30	49.21	17.25
JUL													
AUG													
SEPT													
OCT													
NOV													
DEC													

(a) Pentanes Plus obtained as a specification gas product,
(b) Propane and Butane obtained as specification products, and
(c) Pentanes Plus, Propane and Butane contained in a natural gas liquids mix.

Note: For details on "Prior Period Amendment Effects", see Attachment 2A.

PRIOR PERIOD AMENDMENT EFFECTS												
NGL REFERENCE PRICES	June 2009											
	Propane		*Butanes*		*Pentanes*							
Price before amendments	201.005774		357.424469		470.286872							
Opening Rollover (from prior business mth)	-0.004549		0.003476		0.003707							
Prior Period Amendment Adj. (NGL-100)	0.000000		0.000000		0.000000							
Published Reference Price	**201.00**		**357.43**		**470.29**							
TRANSPORTATION ALLOWANCES	June 2009											
	Pentanes Plus				Propane and Butane				Pentanes Plus, Propane & Butane			
AMENDMENTS	Region 1	Region 2	Region 3	Region 4	Region 1	Region 2	Region 3	Region 4	Region 1	Region 2	Region 3	Region 4
Opening Rollover (from prior business mth)	-0.002759	0.004171	-0.004369	0.004512	-0.001462	0.000222	0.003891	-0.001582	-0.003282	0.003091	-0.000438	0.004745
Prior Period Amendment Adj. (NGL-100)	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Total Amendment Effect	-0.002759	0.004171	-0.004369	0.004512	-0.001462	0.000222	0.003891	-0.001582	-0.003282	0.003091	-0.000438	0.004745
Calculated Transp. Differential	14.938040	23.541282	36.409344	25.247767	40.562918	35.358449	38.569874	60.652697	61.315863	51.822901	60.296332	49.204423
Calculated Transp. Differential after Total Amendments	14.935281	23.545453	36.404975	25.252279	40.561456	35.358671	38.573765	60.651115	61.312581	51.825992	60.295894	49.209168
Published Transportation Allowance	**14.94**	**23.55**	**36.40**	**25.25**	**40.56**	**35.36**	**38.57**	**60.65**	**61.31**	**51.83**	**60.30**	**49.21**

Effective the January 2009 production period, the royalty rates for **methane** and **ethane** will be calculated based on a new royalty formula. The new royalty formula consists of the sum of a price component and a quantity component. The new royalty rates will range from 5% to 50%. **Propane** and **butanes** will have fixed royalty rates of 30%, whereas **pentanes plus** will have a fixed royalty rate of 40%.

The price component of the new royalty formula royalty rate for methane and ethane is determined by the monthly methane or ethane par price (PP)

Price ($/GJ)	r_p
PP ≤ 7.00	(PP – 4.50) * 0.0450
7.00 < PP ≤ 11.00	(PP – 7.00) * 0.0300 + 0.1125
PP > 11.00	(PP – 11.00) * 0.0100 + 0.2325
Maximum	30%
Minimum	Can be negative (-20.25% if PP=0)

The par price is a provincial weighted price determined by the department and published in the Information Letter for each production month. Determination of the par price has not changed under the Alberta Royalty Framework.

The quantity component of the new royalty formula royalty rate for methane and ethane is based on the average daily production (ADP) of the well event. The quantity component is adjusted for either the depth of the well event and/or the acid gas content of the well event.

Quantity ($10^3m^3/d$)	r_q
ADP≤ (6 * DF)	[ADP – (4 * DF)] * (0.0500/DF)
(6 * DF) < ADP ≤ (11* DF)	[ADP – (6 * DF)] * (0.0300/DF) + 0.1000
ADP > (11* DF)	[ADP – (11 * DF)] * (0.0100/DF) + 0.2500
Maximum	30%
Minimum	Can be negative

The ADP for a well event is the total raw gas production in thousand cubic metres (10^3m^3) for the month divided by the total hours of production in that month multiplied by 24. The ADP formula is as follows:

$$\mathbf{ADP} = \frac{\textbf{total raw gas production}}{\textbf{total hours of production}} \times 24$$

Acid Gas Factor (AGF) is a factor that adjusts the ADP of a well event if that well event is producing high amounts of acid gas, that is, if the combined concentration of hydrogen sulphide (H2S) and carbon dioxide (CO_2) is greater than 3% and less than or equal to 25%. If a well event has an acid gas content of less than or equal to 3%, then the AGF of the well event will default to 1.00. If a well event has acid gas content greater than 25% then the AGF has a minimum value of 0.78.

The AGF is determined based on the following formula:

$AGF = [1.03 – (H_2S\% + CO_2\%)]$

The ADP is adjusted by multiplying the ADP by the AGF, that is:

Adjusted ADP = ADP * AGF

The acid gas content of a well event, used by the department for the determination of the AGF, will be according to the records of the ERCB.

A depth factor (DF) is required for all well events, and is calculated based on the measured depth (MD) according to the records of the ERCB for that well event. Information on the MD, of a well event, can be found on the Petroleum Registry of Alberta (PRA) in the 'Infrastructure' section.

The DF is used in the determination of the quantity component (r_q) of the royalty rate; it adjusts the quantity component royalty formula for measured depths that exceed 2000 metres. The DF for a well event is determined based on the following formula:

$$DF = \left(\frac{MD}{2000}\right)^2$$

A well event with a MD greater than 2,000 metres will receive a royalty adjustment based on production from the well event. A well event without a reported MD or with MD less than or equal to 2,000 metres will have a DF of 1.00. The DF is capped at 4.00 for well events with MD greater than or equal to 4,000 metres.

If the MD is

- ≤ 2,000 metres, then the DF=1.00
- >2,000 metres and <4,000 metres, then DF= $\left(\frac{MD}{2000}\right)^2$
- ≥4,000 metres, then the DF=4.00